BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation in Hawaii.	)	DOCKET NO. 03-0371

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PUBLIC UTILITIES COMMISSION

COUNTY OF MAUI'S FINAL BRIEF

CERTIFICATE OF SERVICE

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I. The Primary Issue

The primary issue in this proceeding is whether the Commission should regulate the price of privately used, demand-side distributed generation services. The County of Maui ("COM") does not support regulation of those prices for policy, regulatory, business, and cost considerations. The COM recognize that there are important distinctions between the utility cooperative serving Kauai and the HECO, MECO, and HELCO (collectively "HECO") investor-owned utilities. Accordingly, our statements are directed only to HECO.

A. Policy Considerations

From a public policy perspective, the COM does not support regulating the price of any privately used, demand-side distributed energy resources ("DER") service, including demand-side distributed generation ("DG") services. The Commission does not currently regulate the price of any privately used, demand-side DER service, including solar heating and cooling services, energy efficiency services, electrical and thermal storage services, and electrical generation or DG services. HECO's proposal for the Commission to regulate HECO's price for privately used, demand-side DG services, but not regulate the price for other privately used, demand-side DER services, appears to be discriminatory.

B. Regulatory Considerations

Regulations and regulatory actions in Hawaii do not support the regulation of prices for any privately used, demand-side DER services, including DG services.

HRS Chapter 269 only provides for regulating the price of public energy services. The Commission previously concluded that a company that primarily provided privately used DG energy services would not be considered a public utility, and therefore, the provisions of HRS Chapter 269 would not apply to them. The Hawaii Supreme Court affirmed that conclusion on appeal by HELCO.[1]

C. Business Considerations

Distributed generation are disruptive technologies. Conventional central station power plants are established or sustaining technologies.[2] Disruptive technologies provide differentiated products and services, such as the hot water, air conditioning, emergency power, load management, power quality, and

[1] See COM response to HECO/Maui-DT-IR-41.

[2] COM-RT-1, starting at page 23.

electrical services that are provided by combined heat and power ("CHP") systems. Disruptive technologies primarily compete on the basis of function, reliability, and convenience. Conversely, established/sustaining technologies generally provide commodity services, such as the grid electricity from established/sustaining central generation power plants. Existing/sustaining technologies primarily compete on the basis of cost. There are significant distinctions between disruptive technologies and existing/sustaining technologies, and therefore, disruptive technology business operations should be treated differently.

Markets for disruptive technologies are new and uncertain. Reliable market demand forecasting may not be possible for disruptive technologies, whereas forecasting the market demand for central station power plant electricity can be forecasted with reasonable certainty. HECO's CHP market projections, including those relating to market size, growth rate, and market share, should not be viewed by the Commission as having the same degree of certainty as HECO's utility forecasts.

The business risks associated with competing in a competitive disruptive technology market is much different than the business risks associated with being a monopoly service provider in a regulated utility market. The uncertainties of disruptive technology markets suggest that companies need to be flexible and quick to compete successfully in a competitively functional marketplace. HECO's regulated service approach to competing in a disruptive technology market does not appear to be conducive to flexible and quick adjustments. HECO's regulated CHP services business plan should be scrutinized from this disruptive technology perspective.

D. Cost Considerations

The Commission should consider the above policy, regulatory, and business issues in determining whether HECO's CHP proposal is best for Hawaii's greater energy marketplace--all energy providers and all energy users. HECO focuses on "least cost" considerations to themselves and their ratepayers to justify their CHP program application. This "least cost" focus, further compartmentalized by the matrix of issues agreed upon by HECO and the CA,[3] obscures a broad and forward-looking perspective that takes into account relevant policy, regulatory, and business considerations. For example, the item 1)(A)2 in the matrix excludes DG demand-side management ("DSM") from this proceeding. This exclusion would perpetuate a continuing deficiency of the IRP process and it would preclude the Commission from considering a balanced assessment of all appropriate, available, and feasible supply-side DG resources and DG DSM resources that could effectively accomplish the same objectives.

[3] see HECO-R-600

Regarding HECO's focus on "least cost" considerations to themselves and to their ratepayers, HECO did not compare the "least costs" aspects of DG DSM alternatives. Further, HECO's concerns about uneconomic bypass and stranded costs are unfounded.

D.1. HECO Did Not Compare the Costs of DG DSM Alternatives

HECO did not consider the costs of accomplishing the objectives of their proposed CHP program with non-utility owned DG DSM program alternatives. Until this is done, HECO cannot demonstrate that their regulated service option is the "least cost" resource. DG DSM program options should consider all utility incentives, including lost revenue recovery and shareholder incentive mechanisms. These incentives would keep HECO financially whole and address their financial concerns.

If the non-utility DG DSM program options are shown to be more cost effective than HECO's regulated service option, then HECO's cost justifications become irrelevant. By way of analogy, would it be appropriate for HECO to provide a regulated solar water heating service, even if they could prove that they and all ratepayers would be better off, without first considering a solar DSM option? What if the solar DSM option was found to be more cost effective and functionally comparable to HECO's regulated solar services option? Should HECO still be allowed to proceed? A policy of the IRP process is to consider all appropriate, available, and feasible supply-side resources and demand-side management resources. The omission of DG DSM resources in the IRP process is a major deficiency on the part of HECO.

D.2. "Uneconomic Bypass"

HECO has asserted that use of distributed generation will result in "uneconomic bypass" on their system. They have submitted no evidence to support this assertion.

Uneconomic bypass can occur when the incremental cost of service for the utility is lower than the incremental cost of independently developed resources. The record in this proceeding is quite clear that the opposite is the case in Hawaii: the incremental cost for the utility to develop new resources is significantly greater than the cost of independently developed resources.

Mr. Lazar's Exhibit COM-201, backed by HECO's data responses[4] show unambiguously that the cost of new generating resources greatly exceeds the cost of existing resources. MECO's marginal cost of service study shows that marginal costs are greater than average costs. This means that avoiding new load will avoid more in the way of cost than the utilities would collect in revenue from new customers. This is true even without updating the marginal cost study for the higher cost of the newer power plants that MECO proposes to build.

[4] Responses to COM-Companies-SOP-IR-11 & 12.

D.3. There Is Not a "Stranded Cost Issue" in Hawaii--Systems Are Growing, Not Shrinking

HECO's argument that there are potential stranded cost issues is not supported by history or the record in this proceeding. More than a decade ago, the Commission allowed HECO a lost margin recovery mechanism associated with DSM investments.[5] That mechanism allowed HECO to collect revenues associated with distribution investment that otherwise would have been included in rates for the conserved load. The Consumer Advocate ultimately sought and obtained an agreement from HECO to cease this practice, after demonstrating that HECO had, in fact, experienced growing loads, not shrinking loads, during this period.[6]

A growing system can cover its existing distribution costs with existing prices in two ways. Either it can continue to sell power to existing customers with current levels of usage, or it can "lose" some of the load of existing customers and gain load associated with new or expanding customers, and sell power to them. So long as the load on the utility system is growing, the utility has no stranded costs. This is the expected case for MECO into the foreseeable future - absent aggressive development of DSM and DER, MECO is expected to need as many as five new power plants over the

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[5] Docket No. 95-0142.

[6] Order No. 19093.

next decade or so.[7] If a significant portion of this load growth is met with DER, the Company will still have sufficient sales to cover its existing cost. There is a significant difference between slower growth in sales (as would be the case with a significant shift to DER) and actual reductions in sales (which would give rise to stranded costs).

II. RESPONSES TO THE COMMISSION'S QUESTIONS

The following are the COM's responses to the questions from the Commission's letter dated December 28, 2004.

1. Whether the costs and benefits of distributed generation change in times of excess capacity vs. times of shortage of capacity. If the answer is yes, then given that for the life of any long-term asset there are likely to be periods of excess capacity and shortages, please comment on the time span over which one should measure the costs and benefits of distributed generation.

Response: The Hawaii utility systems are growing in load and have a periodic need for capacity additions. The MECO system is growing at about 5 megawatts per year. With conventional resources, such as the combined-cycle units MECO is planning for the Waena site, each addition is about 20 megawatts, meaning that a new unit initially creates excess capacity, and then the system grows into it over time. This is known as "lumpiness" in resource additions, and is common.

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[7] HECO Application in Docket No. 03-0366, Exhibit H, p. 16.

Distributed generation can overcome the lumpiness factor because individual generating units are measured in the hundreds of kilowatts, not in megawatts. They are much better suited to meeting the load growth of small utility systems like those in Hawaii.

If conventional resources are relied upon to meet load growth, the utility is condemned to a perpetuity of boom-and-bust cycles, where it has a capacity deficiency, leading to higher operating costs imposed on consumers when inefficient units must be run to make up the shortfall, and consumers suffer lower reliability. This is then followed by a period of excess capacity with higher fixed costs imposed on consumers. Consumers lose almost continuously, having an optimally configured system only for a fleeting moment when the load of the system passes through the optimal load-carrying capacity of the resources that feed the system.

Load-matched resources, including DG and energy efficiency, can be developed on an as-needed basis to meet small increments of load growth. If pricing incentives are set properly so that developers of DG derive the maximum benefit by installing generation when it is needed to meet load growth, the boom-and-bust cycle can be avoided. The generation impact fee approach set forth by the COM helps to achieve this, by providing a strong incentive for growing loads to meet some or all of those incremental needs with DG and energy efficiency.

Further, because individual DG resources are smaller in size, the level of reserves that the utility must carry to assure reliable service is lower. This makes it easier and cheaper for the utility to select an optimal mix of resources to minimize costs to consumers subject to reliability constraints.

For any generating resource, the proper time frame over which to measure costs and benefits is the economic life of the equipment. For diesel equipment, this may be up to 20 years, while for wind, solar, and hydro, a longer lifetime may be appropriate. Generally Accepted Accounting Principles establish depreciation rates for each type of equipment used by utilities, and these can serve as a reasonable guide. Witness for Hess testified that even within diesel equipment category, there are measures with different lifetimes, questioning HECO's assumption that it's proposed CHP units would last the posited 20 years without massive rebuilding of the systems.[8]

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[8] Transcripts, Volume II, pages 132-133.

2. How should non-utility owned distributed generation be incorporated into the IRP process, in a manner comparable to the treatment of utility-owned distributed generation, so that there is no market or regulatory advantage of one type over another?

Response: Regarding utility and non-utility owned supply-side resources--resources on the utility's side of the meter--the resource costs of both ownership options to the utility need to be properly reflected. Only utility owned supply-side resources are properly costed. For example, currently both utility owned and non-utility owned supply-side resources are attributed the same costs, that being the costs for the utility to develop and operate the resource themselves. This creates inequities in the IRP process because the cost of a non-utility supply-side resource to the utility is actually the price the utility would pay the independent power producer for the purchased power. MECO's cost of developing renewables appear to be higher than that of independent power producers and therefore, MECO's current approach overstates the cost of non-utility owned renewables. In the event the purchase power price has not been determined, an estimate of the purchase power price should be used.[9]

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[9] Transcripts, Volume III, starting at page 128.

Before discussing the treatment of utility owned versus non-utility owned demand-side resource--resources on the customer's side of the meter--clarification needs to be made as to how these resources are characterized. Until HECO/MECO/HELCO proposed their CHP application with the Commission, HECO was consistent with the rest of the world in the use of the terms "supply-side" and "demand-side" resources. However, to justify their application, HECO changed its definition of supply-side resources. They now deem that the ownership of the DG resource determines whether the DG is a supply- or demand-side resource. Therefore, utility owned DG on the customer-side of the meter is now considered by them as a supply-side resource. This is a contrived definition and should be rejected by the Commission. The term "supply-side resource" was discussed in the public hearing and we appreciate Mr. Hempling's efforts to clarify the confusion surrounding the use of this term.[10] By way of example, before the term "supply-side resource" was clarified, a response by the CA to a COM question appears to indicate that either the CA is confused by this definition or they agree with it. The following is a response by Mr. Herz:

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[10] Transcripts, Volume III, starting at page 156.

> The subject of the testimony was distributed generation or supply-side resources. That was the focus of the Commission -- or the purpose of the Commission's order. That was the direction of the testimony, an so consideration of DSM is not a matter subject to this proceeding.[11]

If the CA disagrees with the definition, then the CA should consider HECO's CHP proposal to be a utility owned demand-side resource and not a matter subject to this proceeding.

Regarding utility and non-utility owned demand-side resources--resources on the customer's side of the meter--the problem with the IRP process is that MECO will not consider these resources, despite recommendations by the COM to do so since 1992,[12] and despite a recommendation to do so made in the 1997 study, "Dispersed Generation Assessment For Maui Electric Company, LTD."[13] which states:

> MECO should evaluate the potential retail competitiveness of distributed generation technologies under implementation scenarios by third parties, as these organizations may offer more cost effective alternatives to the MECO ownership scenario.
>
> MECO should evaluate the potential opportunities of partnering with large

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[11] Transcripts, Volume I, page 60, lines 7-12.

[12] COM-T-1, starting at page 25.

[13] See COM response to PUC-IR-9.

industrial and commercial customers in distributed generation applications which provide both system and customer values.

This is a major deficiency of the IRP process. For example, HECO does not assess the provision of grid system benefits from privately owned CHP DSM in its IRP, therefore, HECO cannot compare that option to its utility-owned, demand-side regulated CHP services proposal. The acquisition of grid system benefits from privately owned CHP DSM should cost less to HECO than utility owned CHP because HECO would only have to pay the CHP owner a rebate, as opposed to having to pay for the full capital and operating costs of a utility owned CHP system. There has never been a level playing field for privately owned demand-side DG in the IRP process and the COM questions whether HECO can create a level playing field if HECO is allowed to directly own demand-side CHP or other demand-side DG and DER resources.

3. Whether transmission and distribution costs will be substantially reduced for CHP or other distributed generation projects set up for peak shaving only.

<u>Response:</u> The only type of DG discussed in this docket to be set up for peak shaving is the virtual power plant concept advocated by the COM.[14] For this specific example, transmission and distribution costs savings

[14] COM-T-1, page 16 and COM-T-2, pages 50-52.

could be realized. The generating units that would be linked by computer to comprise a virtual power plant are all located in load centers, since they are all backup generators to existing facilities. Many of these are in transmission-constrained or distribution-constrained areas that can and should be identified through the IRP process.

The appropriate tool to ensure that these savings are recognized and achieved is for each utility to identify all transmission and distribution capacity additions that they anticipate requiring over a reasonable 5-10 year horizon. For those locations where expansion may be necessary, additional site-specific impact fees for new and growing loads, and site-specific credits for efforts that reduce load (efficiency and/or DG) should be established.

There may be other applications of this beyond the virtual power plant concept, extending into energy efficiency options. As Mr. Lazar testified in the hearing, many utilities have identified location-specific areas on their systems where emphasis programs for energy efficiency have operated. There is no reason not to extend this to DG in areas like Hawaii, where there are so many other obvious benefits for DG.

4. Whether potential loss of revenues to investor owned utilities, due to advancements in technology and the development of new markets is a risk which the utility has been and is compensated through its approved rate of return; and which forms of distributed generation, if any, would fall into the category of advancement risks for which the utility already receives compensation.

Response: The utility is compensated through the rate of return for all of the ordinary business risks it undertakes, including the risk of technological evolution. Clearly one point of the IRP process is to evaluate technological innovation, and to plan for that innovation.

To date, none of the investor owned utility IRPs identify any loss of revenue potential from the evolution of resources identified in the IRP. Each of the systems is expected to have a growing demand for central generation. Even HECO's CHP application anticipates that these resources will meet only a fraction of the expected system load growth. As long as the system is growing, there are no issues of "loss of revenues" or associated stranded cost (discussed below) to be concerned about.

This does not mean that quantum leaps in technology do not pose a risk to the utility. The personal computer decimated the typewriter industry. The automobile made buggy whip manufacturers fail. The same could occur to an electric utility. In fact, if HECO continues to rely on oil as the basis of its system, it is inviting technological responses to inevitable oil supply shortfalls, and should be held accountable if the utility itself becomes uneconomic. That's the purpose of IRP – to plan for the future, to identify risks and opportunities, and to configure the system to meet customer needs at the lowest possible cost.

HECO should not respond to technological opportunity by erecting roadblocks to consumers pursuing economical and environmentally preferable resources. However, that is precisely what HECO is attempting to do in this docket, by demanding unreasonable standby conditions, preferential treatment for company-owned CHP systems, and not supporting creative approaches such as best-efforts standby service and the implementation of the virtual power plant concept. All of this positions HECO for failure if and when technology evolves to the point that customers having realistic options will simply divorce the power company.

5. Whether the utility would have stranded cost in periods of load growth.

<u>Response:</u> We have addressed this issue separately in this brief at Section I.D.3. Simply stated, no, the utility should have no stranded costs during a period of load growth. Development of DG can help delay the need for

expensive new power plants. It can meet load increments with greater precision than can central generation. DG can bridge the time to an era of renewable generating alternatives, helping to avoid a potential crisis of dependence on imported oil. And, simply by reducing load growth on the utility, DG can assist in avoiding the need for expensive resources that would form the basis of costs that could become stranded.

6. Is it reasonable to expect identification of individual project or project zones in the IRP process? What specific modifications to the IRP process should the Commission consider to facilitate such identification?

Response: It is reasonable to identify individual projects and project zones in the IRP process. MECO identified specific projects[15] in the aforementioned "Dispersed Generation Assessment For Maui Electric Company, Ltd." HECO could also conduct a DG due diligence review for planned transmission and distribution system projects.[16] In order to facilitate identification of potential projects and project zones for DG in the IRP, HECO should assimilate its T&D systems planning with its generation systems planning. HECO could start off by doing what they can with existing

[15] Transcripts, Volume III, page 144.

[16] Transcripts, Volume III, pages 151-152.

resources and build upon those efforts in future IRP cycles.

7. Under each of the two scenarios for participation in distributed generation -- utility participation and utility affiliate participation -- what rules and restrictions are necessary to assure that the competition between non-utility projects and utility-owned (or affiliate-owned) projects is evenhanded, meaning that the utility or utility affiliate has no unearned competitive advantage? (Note: although some Parties and Participants may believe that there is no possibility of unearned competitive advantage, while other Parties and Participants might believe that any participation by the utility or an affiliate will distort the market, the Commission urges Parties and Participants to suspend these beliefs for purposes of this question and assist the Commission's consideration of practical approaches.)

Response: Before the HECO regulated service participation option is considered, HECO should first demonstrate that their option is better than privately owned DG DSM programs options. Consideration should include all utility incentives related to DSM, including lost revenue recovery and shareholder incentives mechanisms, in order to keep HECO financially whole. If the privately owned DG DSM options are more cost effective than the utility participation option, then this whole exercise of creating a competitively fair marketplace is irrelevant. The COM recommends that this is the most practical approach to take, before possibly taking the next step of creating a level playing field for the regulated utility service participation option. Also, this step should have already taken place in the IRP process.

Regarding the affiliate ownership option, the COM feels that the most practical approach is the structured competition market model approach presented by the HREA. This approach could yield the greatest benefits to Hawaiian Electric Industries ("HEI"). HECO could facilitate the development of CHP with DSM rebates and be made whole through DSM lost revenue recovery and shareholder incentives, perhaps modified as an outcome of decisions made in HECO's pending rate case. The HECO affiliate could also earn profits for HEI through successful competition in the privately used, demand-side DG marketplace. In the long term, the need for DSM rebates for new construction could be obviated by the establishment of generation impact fees and the utility incentives could be eliminated with the establishment of performance-based ratemaking.

III. Other Main Considerations

A. MECO Has Marginal Costs That Are Far Above Average Costs

While this proceeding deals with all of the utilities, the situation that makes it desirable to move ahead aggressively with DER is most clearly shown in this record for MECO.

The average cost of the proposed new power plants that MECO plans to build, if load grows, comes to $3,000 per kilowatt of capacity.[17]

The average cost of the existing generation rate base for MECO is $687 per kilowatt of capacity.[18]

Therefore the marginal cost of new capacity is more than four times the average cost of existing capacity.

As Mr. Lazar explained in great detail, where marginal costs exceed average costs, increasing sales will result in higher rates to existing customers.[19] It is clearly in the interest of existing customers to avoid load growth that causes a need for new power plants to be built.

Development of policies that encourage customers to rely on DER will help to avoid expensive new power plants, and help to mitigate the rate increases that will otherwise be imposed on all customers of MECO. The strategy recommended by the COM will achieve this objective in several ways:

First, customers that have distributed generation options that are less costly than MECO's central station options will pursue those options, avoiding new high-cost generation and the associated rate increases.

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[17] Exhibit COM-201, page 3

[18] COM-T-2, page 14

[19] COM-T-2, pages 39 - 47

Second, customers that have energy efficiency options that are less costly than MECO's central station options will pursue those efficiency options, avoiding new high-cost generation and the associated rate increases.

Third, customers that have alternate fuels that can meet their needs, including renewable resources, will have an incentive to pursue those alternatives.

HECO's proposal, to allow it to enter into the DG industry in competition with other DG providers, but providing no incentives in the form of cost-based prices for new and growing customers to consider efficiency or renewable resources will not achieve the same objectives. If new customers can continue to force MECO to building new power plants (at marginal cost) but pay MECO only average cost for the power, existing customers will be forced to subsidize this growth through higher rates.

The obvious solution to this is to implement tools that align customers incentives with the Company's costs. To bring the prices faced by new and growing loads into line with MECO's marginal costs of new supply requires an approach like that suggested by the COM.

A principal objective of this proceeding should be to provide cost-based price signals to encourage new and growing customers to pursue DG and DER alternatives that cost less or have higher value than central station power. All options considered by the Commission should be judged on whether they meet this principal objective.

B. Reasonable Standby Rates Are Essential

There is no question that reasonable rates for standby service are essential to encourage the development of DG. There are three different well-defined proposals before the Commission in this docket. In addition, the Consumer Advocate has proposed an ambiguous approach, which it calls "unbundled" rates, but could not provide adequate clarification regarding specifics of the proposal during the hearing process.

First, the COM has proposed that cost-based standby rates be established, recovering a small portion of the fixed costs of standby resources in a fixed charge collected every month, and the majority of the fixed costs in a daily demand charge to be recovered when standby service is being used. Variable costs would be recovered in a time-of-use energy charge. This approach fairly allocates the cost of standby resources among the multiple standby customers who can share the standby resources. This approach is discussed in detail in the rebuttal testimony of Mr. Lazar.

Second, Hess Microgen has proposed that there be "no standby rate." It appears that Hess proposed that standby customers would pay the same demand and energy charges for service that full-requirements customers pay. Because only a portion of HECO's fixed costs are recovered in the demand charge, this approach produces a demand charge not significantly different from that proposed by the

COM. However, HECO would continue to overcharge standby customers through the use of the three load-factor-blocks to recover remaining fixed costs, as most standby customers will have relatively low individual load factors.

Both the COM and Hess agreed that customers using company-owned DG, if allowed, must be subject to the same standby rates as independently-owned DG systems.

The third approach is that advocated by HECO. It would treat company-owned DG very differently, exempting these units from standby rates. HECO's approach would impose prohibitive standby charges on independently-owned DG systems. It is quite clear that the objective of the HECO proposal is to ensure that HECO retains a monopoly on electricity supply in the islands, regardless of whether customers buy utility-generated power or install DG systems. The HECO approach should clearly be rejected.

C. <u>To Encourage DG, Customers Need Reliable Service</u>

The overwhelming majority of the market for DG in Hawaii is currently in the hotel sector, where customers have applications for both electricity and thermal energy. As technology evolves, the COM believes that additional applications will become cost-effective. Hotels serve a tourist economy, and require reliable electric service. Installing stand-alone generation without utility backup is generally not a reasonable option. For this reason, in order for DG to evolve in Hawaii, the provision of reasonable cost standby service is essential.

D. Multiple Customers Can Share Reserve Capacity

Perhaps the biggest misunderstanding in this entire proceeding is the flawed implication by HECO that every DG system requires a utility backup of equal capacity. In fact, a well-developed DG industry, with as many as 100 installations per island,[20] would allow for many DG customers to share a unit of standby capacity.

Mr. Lazar's testimony indicated that the forced outage rate for CHP systems is in the order of 5%, a figure supported by HECO and by Hess during the hearing. In addition, there would be scheduled outages for planned maintenance. As Mr. Lazar testified, if the standby tariff requires coordination of scheduled outages during slack-demand periods in the spring and fall, the utility need only provide enough capacity to serve the expected level of forced outages at any point in time. Not every DG customer will suffer simultaneous failures, and therefore the utility needs only a fraction of the DG capacity in reserve to provide reliable service.

This is precisely the way that HECO plans for its own reserves for its own generating plants. The Company does not assume that all of the units fail at once. Instead, it provides enough reserve

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20 The Rebuttal testimony of Mr. Lazar uses the estimated numbers of CHP systems calculated by HECO, and there were approximately 100 systems projected to be developed on each of Maui, Hawaii, and Oahu.

capacity to cover the unexpected outage of one or two power plants. The same principle should apply to calculating the reserves applicable to standby service. If 20 customers, each with a 500 kw DG unit, have a 5% forced outage rate, then the utility needs only about 5% of the combined capacity of the DG units in reserve. Even if the utility reserved twice as much capacity - 1000 kw - the cost would be split 20 ways, and each customer would pay only 10% of the fixed cost of a reserve generating unit for reliable service. This principle is known in the industry as "diversity" and is extensively used by utilities in planning their expected power needs.

At the transmission and distribution level, the diversity are also present, where more than one customer is served on a single transmission area or distribution line. There may be some locations where there is little or no diversity, but in the primary hotel zones of Maui (Wailea, Kihei, Lahaina, Kaanapali, and Kapalua, there are multiple condominiums and hotels. Therefore it is appropriate that multiple customers share the fixed costs of transmission and distribution capacity that provides standby service.

The approach to standby rates testified to by Mr. Lazar in his rebuttal testimony captures this diversity appropriately. It recovers all of the fixed costs incurred by the utility equitably among the users of that capacity. Each customer pays a portion of the fixed costs in a demand charge that applies throughout the year, and their share of the balance of these fixed costs in a daily demand charge that applies when they actually take standby service. In this way, the Westin, the Marriott, the Hyatt, and the Sheraton (all co-located in Kaanapali) might share both the use and cost of standby generation, transmission, and distribution capacity were they to install DG systems. Under HECO 's approach, each would pay the entire cost of standby capacity, even though the same capacity could serve multiple customers. The HECO approach is, quite simply, designed to make DG uneconomic, in order to allow the utility to retain it's monopoly over electricity supply.

E. <u>The Cost of Reserve Capacity Is Lower Than The Cost Of Baseload Capacity</u>

One important issue resolved in the hearing is that reserve capacity used for standby service is much cheaper than baseload capacity used throughout the year to serve customers without their own generating resources. In cross-examination, the witness for Hess testified that many of their DG customers have their own standby units, and they choose lower-cost machines for standby service, knowing that they will not be used all of the time. This is another important reason why standby fixed charges should be lower than the fixed charges paid by full requirements customers of the utility, who do expect to use those machines all the time.

F. <u>Two Kinds Of Standby: "Firm" And "Best Efforts"</u>

Mr. Lazar proposed two different kinds of standby service.

The first would be the "firm" service, and the utility would be expected to plan for the statistical diversity of demand created by unexpected outages of DG systems. In the example used above, of 20 generating units each with a 5% forced outage rate, each customer would pay for about 5% of the fixed costs of the capacity used to serve them. A portion of this would be paid in the form of a "reservation fee" and the balance on a daily as-used demand charge.

The other service proposed by Mr. Lazar was "best efforts" service, in which the utility would provide service if it had generating capacity available. This service would be appropriate for loads that could be curtailed if necessary. Since the utility would not need to plan any resources to serve a "best efforts" customer, there is really no additional fixed costs incurred to make this service available. However, as Mr. Lazar testified, it is a fundamental principal of rate making that any customer using utility capacity, at any hour, should make some contribution towards the fixed costs. This eliminates unfair "hitchhikers" on costs paid for by other customers. Best efforts service is a good example of why this approach is appropriate. Mr. Lazar proposed that Best Efforts standby service be assessed one-fourth of the fixed costs assessed to a firm standby customer.

This would create an opportunity for the utility (and utility customers) to benefit from a hotel installing a DG system. A hotel installing a DG system might elect to secure "firm" service for it's guest rooms and administrative offices, and "best-efforts" service for water features and laundry areas. If the utility's DG system failed at exactly the same hour that the utility system was under stress, it would be necessary to curtail these activities, but most of the time the utility system is not under stress, and capacity is available to serve such loads. Under this approach, even non-participating customers would benefit, since a portion of the fixed costs incurred to serve them would be paid by the hotel.

G. Suggested Simple Format For "Firm" Standby: Make It Look Like the Schedule P Rate

Mr. Lazar developed a complete standby rate proposal in his rebuttal testimony. It included the following features:

- A small demand charge, that serves as a reservation fee;
- A daily as-used demand charge, that recovers the majority of the fixed costs of standby capacity; this is discounted for demands that occur only during off-peak hours.
- A time-of-use energy charge to recover variable costs.

This approach would ensure that the utility fully recovered the cost of standby capacity, without double-charging multiple customers for the same capacity. It would provide an incentive for DG customers to schedule such things as oil changes at night or on weekends, by allowing them to avoid a portion of the fixed standby costs. It would ensure that those customers that used standby service many hours of the year make a larger contribution to the fixed costs than standby customers that take standby service only a few hours per year. Finally, it would ensure that all standby power users pay the utility for the variable costs of their service.

As the hearing evolved, Hess made it clear that a simpler standby service and rate was important to encourage DG systems. Based on that testimony, we think that the following modifications to Mr. Lazar's proposal would be appropriate:

- Set the demand reservation charge equal to the Schedule J and P demand charges. Those rates currently recover a large portion of the fixed costs in energy charges anyway, so this meets the goal of recovering only a portion of fixed costs in the unavoidable standby reservation charge.
- Recover the remaining fixed costs through a time-of-use energy charge, not through the "load factor blocks" currently used in Schedule J and P. The majority of the fixed costs should be recovered during the on-peak and mid-peak periods, but a portion during the off-peak period.
- Recover variable costs through the time-of-use energy charge.

This would ensure that those customers actually creating a need for standby facilities (i.e., those increasing the utility's daytime loads) would pay for the costs of the standby facilities. It would also ensure that multiple customers sharing the same standby facilities would share the costs, as each customer would pay for standby service costs on the days they use that service.

The resulting rate would look very much like the current Schedule P and J rates, except that instead of load-factor blocks (that would overcharge standby customers), there would be TOU energy charges that would fairly apportion shared standby fixed costs between multiple customers using the same standby capacity at different hours of the year.

The example below shows how the current Schedule P rate could be converted to this form:

Schedule P Rate Elements	Schedule P Rates (HECO, 2003)	Standby/TOU Rate Elements	Standby/TOU Rates
Demand Charge	$9.50	Demand Reservation Charge	$9.50
First 200 kWh/kW	$.072	On-Peak kWh	$.095[21]
Next 200 kWh/kW	$.064	Mid-Peak kWh	$.064
Over 400 kWh/kw	$.061	Off-Peak kWh	$.061

It is crucial that the demand ratchet that currently applies to Schedule P not be applied to the standby rate. The entire point of this rate is to share fixed costs between multiple customers. If

21 The on-peak charge is higher than the charge currently applied to the first 200 kwh/kw, because there are only about 90 on-peak hours per month (4 hours/day Monday-Friday). The same fixed costs must be collected in a smaller number of hours, thus the higher rate.

a demand ratchet is applied, then every customer will pay the demand charges every month, even when they are not using the capacity (and other customers are using the capacity). Standby customers should not have redundant charges applied to their use of capacity.

Of course, the Commission could also apply the same rate form to the Schedule J and P rates, eliminating the archaic load factor blocks with modern TOU blocks. The record is quite clear, from Ms. Seese, that all of the Schedule P customers already have TOU-capable metering. It would probably be necessary to phase in TOU rates for Schedule J customers as the required metering could be installed.

H. Suggested Simple Format For "Best Efforts" Standby: One-Half The Fixed Charges Of Firm Standby

Our discussion of best-available standby rates above suggests that applying the identical rate design to best-efforts customers, but reducing the demand reservation charge. For simplicity, we recommend one-half of the otherwise applicable Schedule P demand charge. The TOU energy charges should remain the same. Under this approach, best-efforts customers will impose no fixed costs on the utility, but will contribute significantly to cost recovery of fixed costs. This will benefit non-participating ratepayers as these charges are used to offset costs that would otherwise be recovered from requirements service customers.

I. COM's Proposed Connection Charge Approach Aligns Costs And Rates Better

The COM has proposed that MECO implement a connection charge, or impact fee designed to recover the difference between the cost of generating resources currently included in rates, and the actual cost of new generating resources. This proposal will put capital-intensive customer-owned resources such as energy efficiency, renewable resources, and CHP on a level playing field with utility-owned conventional generating resources. No other proposal before the Commission would create this level playing field.

The benefits of this approach fall into at least three areas, all of which were discussed by Mr. Lazar at pages 39-50 and 56-69 of his direct testimony.

- First, customers will naturally invest more to build more energy-efficient buildings if they have a choice between investing in efficiency (which is relatively cheap) or paying the utility to invest in expensive new power plants.
- Second, customers will be more likely to choose self-generation (both renewable and CHP) if the capital costs of their investment are being compared with the capital cost of utility-owned conventional generation.
- Finally, this proposal will hold down rates to non-participating customers, eliminating the subsidies that currently exist when MECO acquires a new power plant costing $3,000 per kilowatt, and then files for a rate increase that

applies to ALL customers to help pay for the new power plant.

This approach to rate making is nearly universal in the water and sewer industries. It is nearly universal in the electric industry when new distribution lines are extended. It is an appropriate time to extend this long-accepted practice to the current situation in Hawaii, where high costs of new generating facilities are driving up rates, and traditional rate making practices are discouraging energy efficiency and customer-owned generation.

J. <u>New And Expanding Loads Are Being Subsidized</u>

Under current rate making practices, existing customers must heavily subsidize new and expanding loads. Existing customers have been paying for the cost of existing power plants. When new customers come onto the system, existing power plants must be augmented by newer, more expensive units. These drive up rates. The result is that existing customers are denied the benefit of the investment they have made in existing power plants, and forced to pay for new power plants that are needed only to meet load growth.

The COM proposal addresses this creatively, while avoiding all of the problems cited by critics of the proposal.

- Mr. Gegax, for HECO, criticized municipal impact fees as "using the utility as a cash cow" to support other municipal functions. The COM proposal avoids this in two ways. First, it only collects the difference between marginal costs of new resources and the average cost of existing resources. Mr. Lazar addressed the difference between "full cost" and "marginal minus average" cost impact fees at pages 60-61 of his testimony. Mr. Gegax's criticism was directed at an approach that the COM considered and declined to propose. Second, the COM proposal is modeled after the existing distribution system impact/hookup fee, and all impact fees would go into a dedicated fund; the Contribution in Aid account. This would prevent the alleged misuse of funds claimed by Mr. Gegax.

- Ms. Seese compares the proposal in this proceeding to one made by the Consumer Advocate more than a decade ago. There are important differences. First and foremost, this proposal is directly tied to costs, using the difference between the cost of new resources and existing resources as the basis for generation impact fees. Second, this proceeding is about distributed generation, and Mr. Lazar's testimony demonstrates conclusively that the subsidies of new loads built into the current rate making scheme is discouraging the evolution of economic distributed generation by averaging in the cost of new resources with cheaper existing resources, while a customer considering DG must bear the full marginal cost of new resources.

- Mr. Bonnet testifies about the desperate need for new resources on the HECO system in defense of the HECO's proposed monopolization of the CHP market. He somehow ignores the benefits that the COM proposal would bring in filling those needs, by encouraging efficiency (lower load growth) and DG systems (including customer-sited renewable resources and CHP) by leveling the playing field between utility and non-utility resources, and between supply and demand resources. Mr. Bonnet also ignores the potential to address capacity shortfalls with virtual power plants, such as the one proposed by the COM and the one under development by Portland General Electric.[22]

K. <u>This Aligns Builders "Lowest First Cost" Incentive With The Public Interest.</u>

It is well-recognized that builders of new homes, condos, and hotels are very concerned about "first cost" of construction. This has led them to under-invest in energy efficiency, creating uneconomic and unnecessary load growth. Utilities have responded with expensive DSM programs that include such things as shareholder incentives and lost margin recovery, which the Commission is considering in another docket.[23]

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[22] COM response to PUC-IR-14.

[23] Docket No. 04-0113.

There is a better way to align the interest of builders and of the society at large. If builders must make a one-time payment for the cost of utility facilities that are not included in rates, and make periodic payment (through rates) for the costs are already in rates, they should have an incentive to make the proper level of investment in energy efficiency, load management, and customer-sited generation in new buildings.

L. <u>The Best Time To Install Efficiency, Dg, And Der Is At The Time Of Construction</u>

Clearly the best time to install energy efficiency measures or to engineer in a renewable energy system or CHP system is when a new building is being built. The current system, subsidizing inefficient new load, and then offering utility-funded rebates to install efficiency, is less economical. The COM proposal is unique in encouraging economical investment at the appropriate time, when new buildings are being built.

M. <u>Avoids Rate Increases To Existing Customers To Pay For The Cost Of Growth.</u>

Another benefit of the COM proposal is that it mitigates rate increases to existing customers to pay for new generating facilities. MECO's most recent rate increases have all been associated with the installation of new generating facilities. The same is true for HECO. If growing loads must pay in a one-time contribution the costs that they will not pay through rates, the pressure on existing rates from new resources will be mitigated.

This does not mean that existing customers should never see rate increases. As existing power plants are upgraded for pollution control, or are retired and must be replaced, the higher costs are properly borne by existing customers. But there is no equivalent justification for imposing the cost of new power plants needed to serve load growth on existing loads of existing customers.

N. <u>Difference Between "Full Cost" And "Marginal-Minus-Average" Impact Fees</u>

It is important to understand the difference between the approach to generation impact fees proposed by the COM and the approach that has been criticized by HECO through Mr. Gegax. This is explained in Mr. Lazar's testimony, but merits reinforcement here.

A "full cost" impact fee takes the total cost of facilities needed to serve growth, and divides these by the expected usage of new customers, and charges these as hookup fees. Mr. Gegax criticized these as being a "cash cow" for municipal utilities. He may be correct, if those same customers are required not only to pay for the entire cost of new resources in a connection charge, and then pay rates for service that include a contribution to the investment costs of power supply resources.

The approach proposed by the COM is much different, modeled after MECO's existing line extension charge for distribution facilities, which is embedded in MECO's Rule No. 13, which has been applied for decades. That approach credits customers with the amount they are expected to pay through rates for distribution facilities, and then charges them a one-time fee for the difference between the cost of extending ser vice and what the customers will pay through rates.

The COM proposal for generation works the same way - the entire cost of existing generation is embedded in existing rates. Mr. Lazar's testimony shows that this amount comes to \$687/kilowatt.[24] He credits this entire amount against the cost of new generating facilities in deriving the proposed generation impact fee. And, he goes a bit further. Anticipating criticism that new facilities are more fuel efficient than existing resources, he proposes a generation impact fee of only \$2,000/kW, even though the actual difference between the cost of new generation (\$3,000/kW) and existing generation (\$687/kW) is \$2,313/kW.

The "marginal minus average" approach recommended by the COM clearly anticipates and constructively responds to the criticism that has been lodged at this approach. We are not recommending full-cost impact fees.

24 COM-T-2, page 67

O. Expected Result Of Connection Charges: Lower Loads, Lower Costs, More Efficient Buildings, Greater Use Of Local Resources And Efficiency, Greater Use Of On-site Renewable Resources, And, Most Important, A "Level Playing Field" Between Utility-owned Resources And Customer-owned Resources

The expected result of the impact fees proposed by the COM is quite clear:

Developers will build more efficient buildings, using available energy efficiency technologies, to avoid paying the generation impact fee, where the cost of efficiency is lower than the costs that will be paid by the customer through impact fees and rates (i.e., the cost of the service they demand).

Developers will be more likely to install solar water heaters and/or other on-site renewable resources, where those resources are less expensive to build than the new electric generation facilities they avoid.

Developers of new hotels and condominium projects will be more likely to install CHP systems to meet their thermal requirements and a portion of their electrical requirements where the cost of building such systems is lower than the cost of building new utility generating facilities.

Non-participating ratepayers (the overwhelming majority of the public) will suffer smaller rate increases, as they will only have to pay for the cost of their own service, and no longer will be required to subsidize new and growing loads.

The COM will benefit from lower total energy costs, as the sum of utility costs and consumer costs will be lower under this approach.

The Hawaii economy will benefit from lower reliance on oil, lower outflows of money from the state economy, more reliance on efficiency and local technologies that create local family-wage jobs, and the reliability and diversity benefits of efficiency, renewable resources, and CHP systems.

P. HECO's Concerns Over Capacity Shortfalls Fail To Consider The COM's Proposed Virtual Power Plant Option

HECO contends that they are offering regulated CHP services because of the urgent need to address Oahu's looming power capacity shortfall.[25] This concern does not take into consideration the relatively fast development of a virtual power plant, comprised of standby generators, that could address capacity shortfalls. Received during discovery, the COM obtained a 2003 study prepared for HECO titled, "Commercial and Industrial Stand-by Generation and Interruptible Load: A Site Survey of Large Customers." The study estimated that there was approximately 114 megawatts of standby generation capacity on Oahu that could be incorporated in a DSM program. Based upon observations on Maui and on Kauai after Hurricane Iniki, Mr. Kobayashi estimates that there could be about another 200 megawatts of standby generation capacity that could be

[25] HECO T-6, page 6.

developed on Oahu by upgrading the capacity of old and/or undersized standby generators and by installing standby generators at facilities that do not have standby generators, but could use them. These standby generators could also provide backup services to CHP systems.

A virtual power plant, made up of existing and new standby generators, similar to the system by Portland General Electric,[26] could expediently address the possibility of a capacity shortage, as well as address other utility and customer needs.

Q. Clarification Of The Professional Basis For Mr. Kobayashi's Testimony

The professional basis for Mr. Kobayashi's testimony on the regulatory and business aspects of distributed generation are not only based upon his current position as an energy coordinator in the COM Department of Management. The following is provided to clarify the professional basis for his testimony.

Q.1. Professional Basis For The Regulatory Assessments

Mr. Kobayashi's analysis of how certain DG project proposals related to state laws, court rulings, and agency precedents,[27] is similar to the analytical work he did for four years as a planner in the COM Planning Department. On a weekly basis, he presented project assessments on proposed developments before the Maui

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[26] See the COM's response to PUC-IR-14.

[27] COM-RT-1, beginning at page 4.

Planning Commission, the Historic Commission, and other committees and boards. Each project assessment included an analysis of how all applicable federal, state, and county laws, court rulings, and agency precedents related to the proposed development action. On a daily basis, Mr. Kobayashi made assessments relating to whether a proposed development was consistent with pertinent laws, court ruling, and agency precedents, in the context of assisting citizens with their inquiries about their proposed actions.

Q.2. Professional Basis For The Business Assessments Relating To Disruptive Technologies

Testimony relating to disruptive technologies was based upon Mr. Kobayashi's management of mini-photolaboratories on Maui and Oahu, before being employed by the COM. Mini-photolabs and distributed generation are both disruptive technologies, and by way of comparison, mini-photolabs are to distributed generation, as regional Kodak photoprocessing centers are to central station power plants. The "distributed" photolab technologies used by Mr. Kobayashi changed the structure of the photo processing industry, just as emerging DG technologies are changing the structure of the electric utility industry. Mr. Kobayashi can validate all of the disruptive technology citations in his testimony[28] with personal experiences and observations gained in his work during the transformation of the photoprocessing industry.

[28] COM-RT-1, starting at page 20.

Q.3. Professional Basis For The Business Assessments Relating To Market Power

Testimony relating to market power issues was based upon Mr. Kobayashi's extensive interactions with the DG industry while with the COM, which includes moderating a statewide DG industry forum consisting of a discussion of market power concerns in Hawaii.[29] Testimony was also based upon his pre-COM experiences in the photoprocessing industry. To Mr. Kobayashi's knowledge, his Maui mini-photolab may have been the first retail mini-photolab in the country to compete directly against Kodak in the marketplace that it dominated, the wholesale photoprocessing marketplace. Kodak was also the supplier of the Maui mini-photolab's film and photoprocessing supplies, so directly competing against Kodak created situations for Mr. Kobayashi that are analogous to situations that a DG company would face when directly competing against the electric utility, while also getting its interconnection and standby "supplies" from the utility.

III. ACTIONS THE COMMISSION SHOULD TAKE IN THIS DOCKET

A. Do not regulate the price of privately-used, demand-side DG and DER energy services.

B. Order HECO to incorporate DG DSM programs in the IRP process.

C. Order MECO to prepare proposals for cost-based generation impact fees, time-of-use block rates for commercial and industrial customers, inverted block rates for residential customers, and intragovernmental wheeling

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[29] COM response to HECO/Maui-DT-IR-42, page 56.

rates for the COM, in the contest of MECO's IRP process, the upcoming Act 95 ratemaking proceeding, or some other venue.

D. Order standard and "best efforts" standby rates that are reasonable for DG customers.

E. Order a collaborative examination of the virtual power plant concept in conjunction with the IRP process, and allow cost recovery through the IRP surcharge or a successor mechanism. If a generation capacity shortfall situation becomes acute, the Commission should order the expedient development of a virtual power plant, comprised of existing standby generators.

IV. CONCLUSION

DG products and services are now becoming competitive in the energy services marketplace. Over the next couple of decades, it is reasonable to expect that a broad array of DG DSM services will become fully competitive with central generation and other DER DSM services. It is also reasonable to expect DG and DER to transform the structure of the power grid from a centralized, uni-directional power network into an interactive network of central generation, distributed generation, and distributed electrical and thermal storage resources, interfacing with computer-intelligent appliances, equipment, and facilities. DG and computer-intelligent customer loads can be expected to become commonplace.

The technological and societal forces that drove past regulatory policies are changing. New power plants are now more expensive than older power plants. The benefits accrued from the economies-of-scale associated with central station power plants are being supplanted today by the benefits accrued from the economies-of-mass production associated with DG and other DER technologies. DER services are becoming more competitive against central generation alternatives. Growing societal concerns over environmental, cultural, regional economy, and other quality of life matters require more rigorous regulatory consideration than in the past. As a result, current regulatory approaches and policies are, or are becoming, outdated. This applies not only for matters relating to CHP and DG, but for all renewable energy, energy efficiency, load management, and energy storage DER services.

Hawaii needs a new regulatory regime that is forward-looking and comprehensive--a regulatory regime that can facilitate the development of whatever central generation or DER technology that can provide the greatest amount of public benefits. The COM feels that the incrementalized and compartmentalized approach supported by HECO and the CA is short-sighted and it exacerbates the problems of our existing regulatory regime. Establishing a precedent to regulate the price of a privately used, demand-side DER service, namely HECO's regulated CHP service proposal, suggests the continuation of a regulatory regime that favors regulation over facilitating market competition. Should the Commission regulate the price of future DER services that threaten HECO's market share? Is this the regulatory path Hawaii should take?

The Commission should not be pressured into making stop gap decisions in response to alleged capacity shortfalls or the need to expedite Rule 4 CHP application proposals. If need be, we recommend the expedited implementation of virtual power plants and CHP DSM programs.

We respectfully ask the Commission to fix the systemic problems of Hawaii's regulatory regime, instead of addressing the symptoms of the perceived problems caused by CHP's potentially significant market share. To do this, the Commission must have a vision beyond that of the instant proceeding. In addition to the COM's above recommended actions of the Commission, the Commission should be mindful that actions taken in HECO's IRP processes, the competitive bidding docket, and the forthcoming Act 95 ratemaking proceeding will also have important implications on the future of DG and other DER. Performance-based ratemaking or DG DSM utility incentive mechanisms, for example, could address many of HECO's financial concerns relating to DG, DER, and their DSM applications.

The COM appreciates the Commission's consideration of our recommendations. We are also very grateful for the Commission's efforts to facilitate the development of the record in this proceeding through information requests by the Commission, a panel hearing format, and the use of a highly skilled moderator/consultant.

DATED: Wailuku, Maui, Hawaii, March 7, 2005.

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CERTIFICATE OF SERVICE

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